CANADA

NATIONAL ENERGY BOARD

PROPOSED METHOD FOR THE REGULATION OF TOLLS AND TARIFFS OF THE FOOTHILLS PIPELINE

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This document sets forth the National Energy Board's proposed method for regulating the tolls and tariffs of the Canadian portion of the Alaska Highway Gas Pipeline.

Included as an attachment is a document prepared by the Alaska Gas Project Office of the United States Federal Energy Regulatory Commission entitled "Report of the Alaskan Delegate on Tariff and Operation Phase Rate Issues", dated February 2, 1979 and revised February 16, 1979.

B.H. Whittle
Brian H. Whittle
Secretary

Ce volume est publié séparément dans les deux langues officielles.

18 April 1979

THE NATIONAL ENERGY BOARD'S PROPOSED METHOD FOR THE REGULATION OF TOLLS AND TARIFFS OF THE FOOTHILLS PIPELINE

The Foothills pipeline to which this document refers is the pipeline defined as follows in Section 2 of the Northern Pipeline Act:

> "... the pipeline for the transportation of natural gas from Alaska across Canada along the route set out in Annex 1 to the Agreement..."

In response to a request by the Board on 1 February 1979, Foothills Pipe Lines (Yukon) Ltd. filed the form and content of its proposed tolls and tariffs for the pipeline on 21 March 1979. The filing contained "the form and content" of the tariff, but did not include details of the actual costs that would be charged.

The tariff filed is a "cost of service" form of tariff. This may be described as follows:

> Under a cost of service form of tariff, the regulatory agency allows the utility to adjust its charges in accordance with rules approved by the agency on a monthly basis as costs incurred change. The rules specify the costs that can be recovered under the tariff, the accounting principles to be followed in determining the schedule of tolls, the rates of return allowed on the investment, the depreciation rates, and the other parameters necessary for determining the cost of service.

This is in contrast to a "fixed toll" form of tariff, which is described as follows:

> Under a "fixed toll" form of tariff, a regulatory agency allows the utility to charge a schedule of tolls based on the estimated cost of service. The toll is generally in two parts: a monthly demand charge based on the apportioned capacity of the pipeline equivalent to the maximum daily contracted shipment entitlement, and a commodity charge (per Mcf) related to the actual amount shipped. This schedule of tolls remains unchanged until a new rate proceeding is conducted by the regulatory agency, and until the agency allows the schedule to be altered.

It has generally been accepted that a cost of service form of tariff would be a prerequisite for obtaining private sector financing for the pipeline in the United States and in Canada. In respect of the United States, this view is expressed in the second paragraph on page 4 of the Report of the Alaskan Delegate (attached). In Canada, this was the form of tariff discussed in the National Energy Board's Northern Pipeline Hearings; at that time it was considered appropriate by the Board.

The tolls and tariff for the Foothills pipeline are governed by Part IV of the NEB Act and Part II of the Northern Pipeline Act. In particular, Section 35 of the Northern Pipeline Act reads as follows:

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It has generally been accepted that a cost of service type of tariff would be a prerequisite for obtaining private sector financing for the pipeline in the United States and in Canada. In respect of the United States, this view is expressed in the second paragraph on page 4 of the report of the Alaska Delegate (attached). In Canada, this was the form of tariff discussed in the National Energy Board's Northern Pipeline Guidelines and in each case it was considered appropriate by the Board.

The tolls and tariffs for the Northern pipeline are governed by Part IV of the NEB Act and Part II of the Northern Pipeline Act. In particular, section 22 of the Northern Pipeline Act reads as follows:

"35. Where a company files a tariff at the time the financing of the pipeline is being considered, the Board may approve the form and content of the tariff and the rate of return on the equity investment of the company".

In the Board's view, United States federal and state regulatory authorities and the investment community will require details not only of the form and content of the Foothills tariff, but also of the Board's proposed method for the regulation of the transportation charges under the conditions specified in the approved tariff. This is because the investment community, before committing funds for the financing of the project, will require assurance that transportation charges approved in Canada can be flowed through ("tracked") to the ultimate consumer in the United States without additional approval from United States federal and state regulatory agencies over and above any general authority for "tracking".

In view of the foregoing and as Foothills has filed a cost of service form of tariff, the Board is issuing this preliminary proposal on its method for regulating the tariff in order to permit interested parties to make their views known to the Board during a tariff proceeding, now scheduled to commence on 12 June 1979.

On both the tariff and the method of regulation, the Board is consulting with the Federal Energy Commission as provided for in Section 9 of the Canada/United States Agreement and Section 32 of the Northern Pipeline Act to achieve a reasonably uniform approach on

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In view of the foregoing and as Foothills has filed a cost of service form of tariff, the Board is issuing this preliminary proposal on the method for regulating the tariff in order to assist interested parties to make their views known to the Board during a tariff proceeding, now scheduled to commence on 12 June 1979.

In both the tariff and the method of regulation, the Board is consulting with the Federal Energy Commission as provided for by Section 8 of the Canada/United States Agreement and Section 37 of the Northern Pipeline Act to achieve a reasonably uniform approach on

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these matters for the pipeline as a whole, since the pipeline in the United States and Canada will undoubtedly be considered as a single entity by the investment community.

The purposes of the Board's preliminary regulatory proposal are:

1. to enable the Board to determine prospectively the methods and parameters for computation of the tolls and tariffs for the pipeline, and the means of applying these, which will result in transportation charges that are just and reasonable;
2. to provide visibility for a form of regulation in Canada that will encourage the acceptance, by United States federal and state regulatory agencies, of the principle of tracking transportation charges incurred in Canada; and
3. to provide for a form of tariff conducive to private sector financing of the pipeline.

To achieve these purposes, the method of regulation must recognize the special circumstances of the Foothills pipeline, and should be the least burdensome form of regulation consistent with the purposes to be achieved.

On the surface, it might appear that a cost of service tariff in which a pipeline company's costs are recovered directly from revenues received from shippers would enable the pipeline

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company to include its actual costs in its tariff without these costs being subject to regulatory review. However, major areas of cost will be governed by previous decisions of the Board, arrived at through the public hearing process, which establish the parameters determining the actual dollar cost in a given period. For example, the depreciation charged in a given year would be derived by applying the rate previously approved by the Board to the cost of assets for projects certificated by the Board. The cost of these assets would subsequently be incorporated in a rate base authorized by the Board.

In any given year there would be costs, such as operations and maintenance, that would be largely within the direct control of company management; a proposal for the treatment of this type of cost is outlined in this document.

The proposed approach is as follows:

1. Audits would be conducted by the Board
   - (a) on construction costs during and on completion of the construction period, and
   - (b) on cost of service, annually during the operation of the pipeline.
2. Audit reports would be public documents available for examination by interested parties.
3. Items for inclusion in the initial rate base and cost of service would be subject to testing for prudence by interested parties in public hearings, recognizing, however, that

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(a) certain purchase contracts or classes of contracts would, pursuant to paragraph 10, Schedule III of the Northern Pipeline Act, be specified by the Minister as requiring approval of the Designated Officer prior to execution and would, therefore, have already received regulatory approval, and

(b) charges for monitoring costs by the Northern Pipeline Agency and the Board would have been audited and certified by the Auditor General of Canada and would, therefore, have already been approved by the Government of Canada.

4. Parameters used for the determination of costs to be included in the cost of service, e.g., depreciation rates, allowable return on equity, etc., would be subject to evaluation in public hearings before being approved by the Board. This would take place before operations commenced. They would remain unaltered unless revisions were warranted by changed circumstances, and then only if these were determined by the Board to be significant. Changes would only be made after shippers and interested parties had an opportunity to make representations regarding appropriate procedures for evaluation of proposed changes.

5. Subsequent additions to rate base would be subject to the requirements of Part III of the National Energy Board Act. (Major additions to rate base would automatically require public hearings in respect of applications for certificates of

public convenience and necessity under Part III of the NEB Act. Smaller projects also require prior approval of the Board.)

6. Certain types of costs that are beyond the control of the pipeline company could be flowed through automatically if previously approved through the public hearing process. Examples of such costs are exchange gains and losses on financing costs.

7. For operating and maintenance costs and any other costs where management has a certain discretion, the following principles would apply:

   (a) Foothills would submit annually to the shippers, to other interested parties, and to the Board its estimate of these costs by principal expense component for the ensuing year. Shippers and other interested parties, following discussions with Foothills, could if necessary make representation to the Board requesting changes in the estimates.

   (b) The Board, after reviewing the estimates and considering any representations, and having ordered any revisions found necessary, would approve an estimate of these costs to be incorporated in the transportation charges.

   (c) Overruns and underruns in revenues from the approved estimate would be deferred. At the end of the year, any extra revenues collected would be eliminated by a reduction in the transportation charges in the next appropriate month. The Board would consider

any representations by shippers, by any other interested parties and by Foothills on the reasons for overruns in costs relative to revenues generated, and would then direct the disposition of them. Month-end balances in deferred accounts would include a carrying charge of, say, prime rate plus one per cent.

8. Foothills would be required to give advance notice to shippers, to other interested parties, and to the Board, of any large costs expected to be incurred, if they are of an unusual nature or are not covered by previous rulings or decisions of the Board. Collection of such costs would be deferred pending their disposition by the Board.

9. Because of the essential nature of a cost of service form of tariff, i.e., the recovery of costs as they are incurred, the Board believes that Foothills would have an onus to demonstrate from time to time to shippers, to any other interested parties, and to the Board that it is operating in an efficient and effective way. Although such demonstration would not be an integral part of the tariff, the Board would require Foothills to make such showing.

10. The significant features of the approved regulatory scheme would be incorporated in regulations.

Since no tariff relating to prebuilt facilities has yet been filed, this document excludes any special considerations that might be needed if prebuilding should occur.

REPORT
OF
THE ALASKAN DELEGATE
ON
TARIFF AND OPERATION PHASE RATE ISSUES

I. SCOPE OF THE REPORT

In Orders No. 17 and 17-A, The Federal Energy Regulatory Commission (Commission) requested the Alaskan Delegate to report on the status of tariff issues for the Alaska gas project. This report should be "in the context of the risk allocation framework during the operation phase" and "should provide sufficient discussion to serve as framework for setting the Operation Phase Rate; as well as for acting on the project sponsors' proposed tariff" (Order No. 17-A, p. 6). Upon receipt of this report, the Commission intends to order filing of tariff applications, to request comments concurrently on the tariff applications and the Delegate's report, and then to expeditiously act on the tariff filings. The following analysis and discussion constitutes the report on the tariff and Operation Phase Rate of the Delegate required by the Commission pursuant to Orders No. 17 and 17-A.

In Order No. 17-A, the Commission indicates the important relationship between the project company tariff and the level of the Operation Phase Rate. The project tariff can materially influence the risk that will be borne by equity investors during the operation phase and thus affects the compensation for bearing this risk that must be provided in the Operation Phase Rate allowed by the Commission.

Order No. 17 sets forth an incentive rate of return (IROR) mechanism that will be applied to the Alaska and Northern Border segments of the Alaska gas project. As part of the IROR mechanism, Order No. 17 defines a number of rate of return concepts including the Operation Phase Rate, the Non-Incentive Rate, the Center Rate, and the Marginal Rate. The Operation Phase Rate is defined to be the rate allowed during the operation of the pipeline after a one-time adjustment to the rate base and should compensate equity

investors for only those financial and operating risks incurred during operation. Other risks incurred during the construction of the pipeline are to be compensated for through the Non-Incentive Rate. Risks resulting from the IROR mechanism are to be compensated through the Center Rate of Return. This report will not deal with any risks other than those during operation of the pipeline. As required by Order No. 17-A, the construction phase risks and the Non-Incentive Rate is to be the subject of a separate report by the Delegate.

The project tariff is a lengthy legal and operating document specifying how the company owning and operating a segment of the Alaska gas project will charge its customers (shippers) and the transportation service that the company will provide. The provisions of this tariff play a major role in determining the risks to the investors in the Alaska gas project and which risks are passed on to the shippers and their customers. This report will only deal with the tariffs for the two segments that will be project financed, the Alaskan and Northern Border segments. The Western Leg segment will be an expansion of an existing system built largely by the Pacific Gas Transmission Company which already has a cost-of-service form of tariff.

Other contractual relationships that play a major role in allocating risks among the various parties involved in an Alaska gas project include the gas sales contracts between the shippers and the producers of the gas at Prudhoe Bay and the tariffs of the individual shippers. Shippers are likely to be interstate natural gas companies and are likely to be equity investors in the project. The key issue concerning the shipper tariffs is the extent to which the shippers will be allowed to automatically pass on changes in the cost of transporting Alaska gas to their own customers without prior approval of the Commission. Some form of automatic tracking may be necessary to avoid delay and reduce risks to the shippers and investors in the project. However, the issues concerning the gas sales contracts and shippers tariffs are not the subject of this report and will not be discussed further.

This report covers two primary subjects. The first is an analysis of the major issues and alternative provisions in the project company tariffs. The evidentiary proceeding before Administrative Law Judge Litt (El Paso Alaska Company, Docket No. CP 75-96 et al, referred to hereinafter as "the FPC proceeding") developed a substantial record, and the Initial Decision by the Administrative Law Judge (ALJ) offers a number of recommendations to the Commission concerning the tariff. The circumstances on which the ALJ based his recommendations, however, were subsequently altered by the President's Decision, which imposed a number of terms and conditions concerning the tariff (President's Decision, pp. 36-38). Consequently the findings of the ALJ may have to be reassessed in light of changed circumstances. By the end of the FPC proceedings, the project sponsors, the Commission staff, and other interested parties were able to reach agreement on a number of important tariff issues. This report will first briefly describe those features of the project tariff where there seems to be little disagreement.

Next this report will discuss the tariff issues where there is substantial disagreement and controversy. For each issue, alternative tariff provisions will be discussed and the effect of each provision on the operation phase risk, on the feasibility of private financing, and on consumers will be described. The positions of the various parties as presented at the proceeding including the recommendations of the ALJ will be summarized. Where relevant, later recommendations or requirements in the Federal Power Commission's Recommendation to the President, the President's Decision, and the Commission's Comments on the Decision will be presented.

The second major subject of this report is the financial risks borne by equity investors during the operation of the pipeline and the level of the Operation Phase Rate necessary to compensate for this risk. There is substantially less evidence on financial risks and rates of return than on the tariff issues. Little evidence was presented at the FPC proceedings. This was a subject reserved for a second phase of an Alaska gas proceeding after the preferred system was chosen from among the three competing proposals. The ALJ did make some recommendations about rates of return but these are only relevant for what is now called the Non-Incentive Rate rather than for the Operation Phase Rate which is the subject of this report (See Initial Decision, pp. 369-370). Also the requirement for an IROR mechanism and the limitation on any charges to consumers prior to completion in the President's Decision substantially change the risks to be borne by investors. Some discussion of rates of return was also provided in the comments on the two notices of proposed rulemaking concerning the IROR mechanism.

This report will describe the risks during operation for which the Operation Phase Rate must provide compensation and will compare the magnitude of these risks with the risks borne by investors in conventional pipelines in the lower 48 states. The form of the pipeline tariff allowed by the Commission, however, will play an important role in determining the magnitude of these risks.

II. RESOLVED TARIFF ISSUES

Cost of Service Tariff

In teh FPC proceeding, the sponsors of the three competing projects, the Commission Staff, most other interested parties, and the ALJ concurred that the cost-of-service form of project tariff was required for private financing of this project instead of the more conventional fixed rate tariff. Later the Commission, in its Comments on the Decision (p. 50), accepted in principle the cost-of-service form of tariff. All tariffs for a regulated utility are based on the cost of rendering service but differ in the circumstances and procedures to be used to alter the rates charged for the service when costs increase or decrease.

Under a fixed rate tariff, a regulatory agency allows the utility to charge a schedule of rates based on the estimated cost of service. This schedule of rates remains unchanged until a new proceeding is conducted before the agency, and the agency allows the schedule to be altered.1/

Under a cost-of-service form of tariff, as costs change the regulatory agency allows the utility to adjust its charges on a periodic basis in accordance with a formula approved by the agency. The formula specifies the costs that can be recovered under the tariff, the accounting principles to be followed in determining the schedule of rates, rates or return allowed on the investment, depreciation rates, and other parameters necessary for determining the cost of service. The agency also may audit the costs recovered to assure their reasonableness and prudency. Many tariffs are in fact a mixture of the fixed rate and cost of service tariff. Interstate gas pipelines generally are required to use a fixed rate tariff, yet can usually pass through automatically changes in the unit cost of purchased gas without filing a major rate change in which a complete cost of service study is submitted and litigated.

1/ The specific procedure followed by the Commission for gas pipelines is the following. The pipeline files a new schedule, which goes into effect within six months of filing depending on whether and for how long the Commission suspends the new schedule. The schedule is subject to adjustments pursuant to a final Commission order thereon.

In general the various parties in the FPC proceeding accepted the need for a cost-of-service tariff because of the greater assurance it would give to financial investors that the cost of the project would be recovered without delay and that adequate funds would be available to cover operating costs, debt service, and the other fixed obligations of the pipeline. However, there was substantial disagreement about the precise form of this tariff, and these issues are discussed below.

Charges Prior to Completion of the System

During the FPC proceedings, two concepts were advanced that could result in charges to gas consumers prior to completion of the project. The first was some form of an "all events" tariff which would require gas consumers to pay a charge adequate to recover the debt investment and, possibly, the equity investment in the project in the event that construction of the project was started but never completed. In other words, consumers would provide a completion guarantee to investors (see Initial Decision, pp. 354 and 392).

The second concept is commonly described as inclusion of construction work in progress (CWIP) in the rate base during construction (see Initial Decision, pp. 393-400). Essentially, consumers would be asked to pay during construction for the interest cost of funds borrowed and a rate of return on equity invested. This would be instead of adding these capital charges, commonly referred to as an allowance for funds used during construction (AFUDC), to the rate base of the project at the time of project completion to be recovered through charges to consumers during operation. Inclusion of CWIP in the rate base would reduce the financing requirements of the project.

Regardless of the merits or disadvantages of these two concepts, the President's Decision limits such tariff mechanisms in the second finance condition which states:

> Neither the successful applicant nor any purchaser of Alaska gas for transportation through the system of the successful applicant shall be allowed to make use of any tariff by which the purchaser or ultimate consumer of Prudhoe Bay natural gas is compelled to pay a fee, surcharge, or other payment in relation to the Alaska natural gas transportation system at any time prior to the completion and commissioning of operation of the system. (President's Decision, pp. 37-38).

The exact definition of the phrase "completion and commissioning of operation", however, has not yet been specified and is discussed in the next section.

III. CONTROVERSIAL TARIFF ISSUES

Billing Commencement Date

As discussed in the previous section, the President's Decision limits charges to customers for the project prior to the "completion and commissioning of operation of the system." A major issue for the Commission is to define this phrase. The project tariff will specify when or under what conditions the pipeline company can begin to charge shippers of gas for their share of the cost of service of the pipeline. The Commission must determine if the project tariff is consistent with this condition of the President's Decision and other legal requirements.

Financial investors will carefully examine this billing commencement feature of the project tariff and the Commission's interpretation of the condition in the Decision. Investors will favor a tariff provision that provides the greatest certainty that the tariff will go into effect as soon as possible in order to reduce the financing requirements for the project and to initiate the recovery of capital. Long delays in the initiation of charges to customers adds to financial charges during construction (AFUDC) and strains the ability of the investors to raise the funds necessary to finance the project. In view of the stringent conditions imposed by the Decision concerning financing (prohibition of consumer or taxpayer guarantees), the report accompanying the Decision, in any case, notes that "...skillful financial packaging and risk - benefit balancing will be required" (Decision p. 106).

There are at least four interpretations of this condition in the Decision concerning billing commencement date:

I. Charges to gas consumers may begin when all segments of the project are complete and gas is being transported. (In the event of "prebuilding" the southern segments to carry Alberta gas, charges may begin for these segments in advance of completion of the other segments.)

II. Charges may begin when all segments are capable of rendering service even if, for whatever reason, gas is not being transported. (In the event of "prebuilding" the southern segments to carry Alberta gas, charges may begin for these segments in advance of completion of the other segments.)

III. Charges may begin for each particular segment of the system when that segment is capable of rendering service even if, for whatever reason, other segments are not capable of rendering service or gas is not being transported.

IV. Charges may begin at a date certain to be specified by the Commission even if none of the segments is capable of rendering service or gas is not being transported.

Clearly the third or fourth definition would provide greater assurances to investors that the project would generate revenues without long delay. The following will analyze each of the four definitions in turn.

The Commission Staff seemed to favor Definition I (all segments complete and transporting gas). This definition would clearly satisfy the requirement in the Decision and the Natural Gas Act. Alcan Pipeline Company (the predecessor company to the current sponsor of the Alaska segment of the project, Alaskan Northwest) argued that the Commission may have no legal authority to place a tariff into effect until the company is a "Natural Gas Company" pursuant to the Natural Gas Act (Initial Alcan Tariff Brief, p. 17). Section 2(6) of the Natural Gas Act defines a natural gas company as a "person engaged in the transportation of natural gas in interstate commerce or the sale in interstate commerce of such gas for resale." Consequently, it may be unlawful for a project company to charge shippers pursuant to an FERC approved tariff until gas is actually being transported.

With respect to Definitions I and II, the phrase "completion and commissioning of operation of the system" must be read in conjunction with the predelivery of Alaskan gas using Alberta gas transported through southern segments built in advance of the northern segments contemplated in the President's Decision (pp. xii and 92). Thus the Decision should be read to authorize charges for the delivery of Alberta gas through the prebuilt southern segments even though the northern segments have not yet been completed.

Definition I imposes a major financial risk on the investors in any one segment. Each segment will be owned by a separate legal entity distinct from the shipper companies and independent of the producers. Definition I would impose the risk on each segment of a long delay in receipt of revenues or conceivably a complete loss of revenues because (a) another segment was delayed in completion or (b) production from Prudhoe Bay was delayed. It could be argued that investors in a company owning one segment should not be penalized for failure of another company to complete its segment or to produce the gas at Prudhoe Bay.

Definition II (all segments complete) would not hold investors in the pipeline responsible for delays in the startup of gas production from Prudhoe Bay but would penalize investors in any one segment for delays in startup of another segment. From the investors perspective, this reduces risks compared to Definition I but still treats the entire system as a single entity ignoring differences in ownership between segments and the fact that some segments will be in Canada.

Definition III (a particular segment complete) may be consistent with past practice in lower 48 pipelines. The emphasis in regulation of new additions to gas plant for lower 48 companies has been to assume that new facilities are added to gas plant in service and thus accrual of AFUDC ceases "when the facilities have been tested and are placed in or ready for service" regardless if the addition is actually rendering service (see Accounting Release Number AR5 (Revised), effective January 1, 1978). An early "in-service date" has been advocated in the past for pipelines since it reduces the AFUDC included in the rate base. This definition would recognize that each segment will be a separate legal entity with different investors. Such a provision would also protect investors in U.S. segments from any financial hardship which might be imposed by delays in Canada, if such should occur.

Definition IV (date certain) would provide the greatest certainty to investors that delays would not impair the financing of the project. Such a billing commencement date is not unprecedented. Alcan has argued that the Commission has allowed tariffs for nuclear power plants to take effect on a date certain, for example, the Yankee Atomic Power Company (Initial Alcan Tariff Brief, p. 16). Alcan's tariff

proposed in the FPC proceedings would commence billing when the Alaska facilities were complete or, in any event, no longer than four years after the beginning of construction (Initial Alcan Tariff Brief, p. 13). This definition, however, seems to clearly violate the intent of the Decision to bar charges commencing prior to "completion and commissioning of operation" and could probably not be defended as a valid interpretation of the Decision.

Interim Rate/Phasing

During the FPC proceedings, two proposals were made to reduce charges during the early months of operation when gas throughput may be less than the design capacity of the system due to the time necessary to start up production at Prudhoe Bay or operation of the pipeline. Arctic Gas proposed a phasing method where some portion of depreciation expense and return on rate base would be deferred until full capacity throughput was reached (See Reply Brief of Arctic Gas, p. 5). The Commission Staff argued instead for an interim rate where a fixed reduced charge per unit of gas would be levied on the smaller initial volumes (Initial Staff Tariff Brief, p. 5). This revenue would be a credit against the construction work in progress account and thus the rate base of the project when full through-put was achieved. The interim rate would last no longer than one year.

In the tariff proposed by Alcan in its initial application to the Commission, no interim rate or phasing was proposed (see Initial Alcan Tariff Brief, p. 18). Shippers would be expected to pay for their contractual share of the cost of service of the pipeline when the facilities are capable of rendering service. In other words, full charges to shippers would commence when the pipeline was complete even though throughput may be at reduced levels or nonexistent.

The criticism of this provision is that early consumers of Alaska gas could be asked to pay a very high transportation cost per unit of gas or to pay even if no gas is being transported. Also marketability of the gas could be impaired by the high initial cost. However, it must be noted that this pipeline is only a contract carrier for the shippers and is not a purchaser of Alaska gas. If investors in the pipeline are held responsible for delays or inability of shippers to tender gas for transportation when the pipeline is able to render service, their risk is substantially increased.

A major advantage of Alcan's proposal is that it would assist in financing. The threat of a long period of either no revenue or only partial revenues after construction was complete increases the total financial investment in the project and postpones payment of principal and interest on the debt investment. Also an interim rate or phasing of charges increases ultimate costs to consumers by increasing financing charges or AFUDC in the rate base and the Operation Phase Rate.

The ALJ found the interim rate proposal superior (Initial Decision, p. 409). However, again his decision was in the context of assumed consumer or government investment guarantees. In light of the much more difficult task of financing this project resulting from the President's Decision, the Commission's need to provide a favorable environment for financing may require approval of a tariff that does not require an interim rate or phasing. The probability is small that there will be a long period of reduced throughput after construction is complete and thus inclusion of an interim rate will most likely be of little or no net benefit to consumers. However, the risks to investors will be reduced by elimination of an interim rate provision, and this will materially assist financing.

Penalty for Service Interruption

Almost without exception all parties to the proceedings including the project sponsors agreed to some form of penalty to equity investors if the pipeline was unable to fulfill its contractual obligation to transport Alaska gas. Such penalties were endorsed by the ALJ (Initial Decision, p. 404) and the FPC in its Recommendation to the President (p. XII-43). A penalty would provide economic incentives for the pipeline owners to assure continued uninterrupted service. The major concern, however, of the various project sponsors is that the penalty should not be so severe or in a form that would jeopardize the financing of the project. If the penalty on the return to equity was so severe that debt investors felt debt service or even debt coverage might be significantly impaired, then the project sponsors' ability to privately finance the project could be impaired.

The sponsors of the Alcan project in the FPC proceeding argued that the return on equity should be reduced in proportion to the reduction in service if the reduction in service for any one month is greater than 20 percent of the contract quantity in the agreements with the shippers. In other words, if the pipeline was only able to carry 80 percent or more of the contract quantity there would be no reduction in return on equity. However, if the pipeline capacity was reduced to less than 80 percent over a one month period, for example, 70 percent, then the return on equity (and related income taxes) would be reduced proportionately, for example, reduced to 70 percent of its normal level for that month. After a service interruption, the pipeline would have an unlimited period to try to recover the loss in equity return by transporting more than the contracted quantity if the shippers were willing to tender excess quantities. The make-up quantities for which the pipeline suffered no loss in return on equity would be transported first and then the quantities for which the pipeline did suffer a reduction in return on equity.

The Commission staff argued that the reliability of pipeline operations is such that a penalty to equity return should begin when the ability of the pipeline to render service is reduced below 100 percent of the contracted quantities, in other words, no leeway or cushion should be allowed before the penalty takes effect. Judge Litt compromised on a level of 90 percent between the sponsors request for 80 percent and the staff's recommendation of 100 percent (Initial Decision, p. 404). The ALJ further would restrict the period of make-up transportation to no more than one year as opposed to the sponsors request for an unlimited period for make-up of the deficiency in transportation and return on equity.

A much more controversial modification to the project tariff, however, was recommended by the ALJ. Based on his belief that equity investors should be subject to the risk of a complete loss of their investment in the event of a prolonged inability of the project to transport gas at the contracted quantities, he stated that

"...it may be necessary to modify the cost-of-service tariff of the transporter to assure that collection of the depreciation charge does not recover equity capital during periods of prolonged continuous outage. A 'grace period,' not to exceed 30 days, for example, would be appropriate, after which the opportunity to recover equity capital would not recur until such time as service resumed. To the extent that lost service could be made up by excess deliveries within one year, shippers should pay additional charges to reimburse the disallowed equity recovery." (Initial Decision, p. 392).

This recommendation was discussed but not endorsed in the FPC's Recommendation to the President (p.XII-43) as part of two hypothetical financing plans.

In addition to substantially increasing the risk to equity investors and thus requiring a higher Operation Phase Rate, this recommendation also could substantially increase risks to debt investors. Debt repayment or retirement will be at higher rates than the normal 4 or 5 percent depreciation rate allowed for tariff purposes. Thus, during the earlier years of operation, debt repayment may be larger than the total allowed depreciation charges of the project. Consequently, any reduction in the depreciation charges allowed to be recovered through charges to shippers could impair debt service. The ALJ's recommendation, to be accepted by investors may have to be conditioned or modified so that debt service would not be impaired.

Even with this modification, debt coverage ratios could be substantially reduced. Debt investors are concerned about protection of their investment in highly unlikely situations. Even if the tariff approved by the Commission would allow the project to levy charges on shippers adequate for debt service in all events, debt investors may be concerned that the pipeline may be unable to actually collect all of the revenues allowed by the tariff. For protection against this event, they look for adequate debt coverage or a cushion of revenues in excess of those required merely for debt service. Judge Litt's recommendation would greatly reduce debt coverage during a prolonged service interruption. Further, the Initial Decision is based on the assumption of both consumer and government guarantees of debt. Without these guarantees, his recommendation concerning prolonged

service interruptions may no longer be consistent with private financing of the project. For these reasons, the Commission must examine very carefully the implications for financing in its consideration of this matter.

Billing Procedure

During the FPC proceedings, two alternative procedures were proposed to calculate the charges for transportation services to be paid by the shippers. The first would be to estimate the cost of service of the pipeline over a future six month period and then fix a constant monthly charge to recover this estimated six month cost of service. In the event that the estimate deviated from the actual cost of service, any accumulated underchange would be added to, or any overcharge substracted from, the charge levied over the following six month period.

The second approach advocated by the Commission staff would be to simply bill shippers monthly for the actual costs of service incurred during the previous month (Staff Initial Tariff Brief, p. 6). This could result in charges changing from month to month but would avoid any overcharging or undercharging.

The arguments either for or against these two alternatives do not seem especially compelling. The advocates of the estimated billing procedure argued that this would be preferred by the shippers and was needed to assist them in flowing through costs in their proposed transportation cost adjustment clauses. As indicated above, the issue of tracking costs through the shipper tariffs is not addressed in this report. However, if the Commission does allow tracking of Alaska gas transportation costs, this may be an argument in favor of the estimated cost billing procedure. Even in this event, shippers' concern about the need for the estimated cost billing procedure may have largely been eliminated by recent Commission changes to the purchased gas adjustment clauses which allow interest or carrying charges to be earned on deferred purchased gas cost balances (see Order No. 13).

The ALJ found "nothing illegal or unfair" about this estimated cost billing procedure and that "no party has shown adequate justification for rejecting this procedure" (Initial Decision, p. 408). If the sponsors of the Alaska gas project desire to utilize this estimated cost billing procedure, there seems to be little justification for not allowing them to do so.

Miscellaneous Tariff Issues

During the course of the hearings, the Commission staff objected to a number of other relatively minor features of the various tariffs proposed by the sponsors of the competing applications. Later in the hearings, the sponsors of the three projects modified their tariffs to accommodate some of the objections of the staff. The ALJ, in general, concluded that these adjustments proposed by the staff should be made (Initial Decision, p. 410). When the sponsors of the Alaska gas project file their revised tariff with the Commission, it should be examined to see if the sponsors have accepted the changes advocated by the staff and approved by the ALJ.

IV. OPERATION PHASE RATE

Analytical Approach

The Operation Phase Rate according to Order No. 17 shall be set by the Commission "within the general range of rates of return for other pipelines with similar operating risks" (Terms and Conditions No. 12). In setting an Operation Phase Rate for each segment of the system, the central issue is the financial and business risks faced by investors in this pipeline during operation compared to the average or typical interstate gas pipeline.

A review of rate cases over the last three years indicates that the average rate of return allowed by this Commission for gas pipelines has been approximately 13 percent and the average proportion of common equity in the capitalization has been approximately 45 percent. The question for the Commission to resolve is whether the risks during operation of the Alaska gas pipeline compared to the normal or typical lower 48 pipeline justify a rate of return higher or lower than the average of 13 percent.

The Operation Phase Rate only provides compensation for risks during actual operation of the project. The risks borne during the construction of the project are to be compensated for through the Non-Incentive Rate of Return. The difference between the Non-Incentive Rate and the Operation Phase Rate is the Project Risk Premium. Pursuant to Order No. 17-A, the Non-Incentive Rate shall be the subject of a separate report from the Alaska Delegate. Risks created by the IROR mechanism itself are to be compensated for by the Center Rate of Return which exceeds the Non-Incentive Rate by an amount equal to the IROR Risk Premium.

Definition of Risk

Though an analysis of risks to investors is a common approach to analyzing the rates of return required for investors in regulated utilities, the concept of risk used is often imprecise or losely defined. For purposes of this analysis, it is usefull to distinguish between two broad categories or types of risk.

Risk for gas pipelines in general is the result of certain events that may cause actual or realized rates of return to deviate from the rate of return allowed by the Commission. A precise measurement of risk requires knowing the probability of such an event and the effect that this event would have on the rate of return. In practice, listing all of the future events that could cause rates of return to fluctuate is impossible as is the measurement of the probability that a particular event will occur

A categorizing of risks is, in effect, a categorizing of those events that could cause rates of return to fluctuate. Broadly speaking, the first and most important category of events are those that would cause the realized rate of return to fall below the allowed rate. For example, suppose that the probability of Event A occurring in any one year on the Alaska gas pipeline is 10 percent. Suppose also that if Event A does occur, the realized rate of return for that year will be reduced by three percentage points (three hundred basis points) from the allowed rate. Further suppose that this event would never occur in a lower 48 pipeline. In order to provide minimum compensation for the risk of Event A occurring, the Commission should increase the allowed rate for the Alaska pipeline by 0.3 percentage points (30 basis points) over the rate allowed for other pipelines (0.3 = .10 X 3.0). On the average taking into account the probability of Event A occurring, the investor in the Alaska gas pipeline would then earn no more or no less than an investor in a typical pipeline.

The second category of risky events are those events which are just as likely to increase the realized rate of return as to lower it. Such an event creates general uncertainty about the realized rate but does not bias the realized rate either down or up. It is generally recognized that some compensation to investors should be given for

greater variance in rates of return even though the realized rate is just as likely to be above the allowed rate as below it. In other words, investors prefer a certain return rather than a return that could fluctuate both up and down. The compensation for this type of risk, however, should be much less than for the first category of risky events discussed above.

Ideally, the Commission should have before it a complete listing of the various events that could cause the realized rate to deviate from the allowed rate, the probability of that event occurring, and the effect of the event on the rate of return. In practice, one can hope for a partial identification of some of the events with a subjective guess as to the probability of the event occurring. What makes any analysis of the risks faced by investors in the Alaska gas project so difficult is that there is very little data or experience to judge the number, probability, or impact of these risky events. The following analysis will attempt to identify those events that could cause the realized rate to fluctuate and to estimate the financial risk to investors from each of these events for both the Alaska project and the normal or average lower 48 pipeline.

Changes in Cost

Fluctuations in the cost of service of a pipeline resulting from changes in operating and maintenance costs, changes in financial costs, or any other component in the cost of service will mean an increase or decrease in the return to equity until a change in rates is approved by the Commission (fluctuations in throughput are considered in the next section). Under the normal or fixed-rate tariff, the typical lower 48 pipeline may experience a regultory lag in the approval by the Commission of a change in rates to compensate for a change in costs. Under the cost-of-service tariff proposed for the Alaska gas project, there would be no lag.

Thus there is some risk that a lower 48 pipeline may realize a rate of return above or below the allowed rate for some period until the Commission acts. Because inflation increases pipeline costs as well as other costs, there seems a greater probability that actual costs will be above estimated costs and thus the realized rate will be below the allowed. The cost-of-service tariff for the Alaska gas project provides a high degree of protection against this risk. Thus the risk resulting from fluctuating costs is somewhat less for the Alaska gas pipeline compared to the typical pipeline.

Changes in Throughput

Unanticipated changes in throughput will result in changes in cost of service per unit of throughput and may alter the revenues and earned rates of return depending upon the form of the tariff. The Alaska gas project will differ substantially from lower 48 pipelines both in the events that could cause a fluctuation in throughput and the tariff treatment of the fluctuation.

A pipeline can experience a decline in throughput either from some production problem in the field that temporarily or permanently reduces daily deliverability or from the exhaustion of proven reserves without sufficient new discoveries to offset the decline. Since the typical lower 48 pipeline derives its supply from a number of different fields and reservoirs, it is not likely that the pipeline would experience a major decline in throughput because of field deliverability problems. However, the Alaska gas project will be supplied primarily by the enormous reserves at Prudhoe Bay. There is little production experience for this reservoir, and there is a small probability that the field may not be able to produce at the level of 2.4 BCFD anticipated in the Decision (p. 89).2/ Further, all gas will be processed and conditioned at a single facility which could experience operating problems.

A decline in throughput due to reserve depletion has a much higher probability of occurring for a lower 48 pipeline than for the Alaska gas project. In recent years the trend for most lower 48 pipelines has been declining production. Prudhoe Bay, by all accounts, has adequate reserves for at least 20 years of production at the rate of 2.4 BCFD.

If a decline in throughput occurs, a lower 48 pipeline could experience a temporary reduction in return on equity because of the lag in applying for and receiving a rate increase. However, the period of suspension for rate increases imposed by the Commission is usually five months or less. Also most pipeline tariffs utilize a demand charge to recover a portion of the fixed costs of the pipeline. This demand charge would not be reduced due to a reduction in throughput thus mitigating the reduction in revenues and

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2/ See the very extensive testimony and exhibits on this subject in the record of the hearings before the Senate Committee on Energy and Natural Resources at the time of consideration of the President's Decision. Alaska Natural Gas Transportation System, Hearings before the Committee on Energy and Natural Resources, United States Senate, September 26, 27, October 11, 12, and 25, 1977. (Publication No. 95-73)

return on equity. The cost-of-service tariff for the Alaska gas project will eliminate any regulatory lag and thus provide a high degree of protection against the risk of decline in throughput.

Though the Commission will allow rates to increase as throughput declines for both lower 48 pipelines and the Alaska gas project, eventually marketability problems may arise. A concern often voiced by lower 48 pipeline companies is that declining reserves to production ratios may eventually result in low levels of throughput and thus an inability to recover their investment in the pipeline. This could happen if the high unit costs of transportation result in the gas being unmarketable and thus the companies are unable to sell the gas at the rates allowed by the Commission. The Office of Regulatory Analysis from the Commission's staff has argued that the Commission has increased allowed rates of return by 2.5 percentage points in recent years to compensate for this risk (see Comments on the Revised Notice, pp. 5-8).

The Alaska gas project will also face a similar or even larger risk because of the high costs of transportation. If production problems should occur at Prudhoe Bay, the cost-of-service tariff will allow an automatic increase in cost per unit of throughput. However, shippers and distributors may find it difficult to market the gas since the transportation costs for the Alaska gas even at full throughput will be substantially higher than other gas because of the large construction costs.

In conclusion, the risk of declining throughput due to reserve depletion is higher for the conventional lower 48 pipeline, the risk of declining throughput due to production or deliverability problems is greater for the Alaska gas pipeline, the cost-of-service tariff for the Alaska gas project provides greater protection against the risk of decline in throughput, but marketability problems resulting from reduced throughput are greater for the high cost Alaska gas. On balance it seems that the risk to investors due to fluctuations in throughput are modestly greater for lower 48 pipelines.

Service Interruption

All pipelines face the possibility that operating difficulties may reduce the capacity of the pipeline to transport gas. For a conventional lower 48 pipeline, the financial penalty for a severe service interruption can be large. A reduction in the amount of gas that can be delivered reduces revenues but less than in proportion to the reduction in throughput due to the demand charge in the typical tariff. If the service interruption is of long duration, the pipeline company could request a rate increase to allow charges on the remaining throughput to cover the cost of service.

This penalty for service interruption seems substantially more severe than contemplated for the Alaska gas pipeline by the project sponsors. As discussed previously, the project sponsors propose a service interruption provision in the tariff that would only reduce equity return proportionately to the service interruption and only for that segment which experienced the service interruption.

On the other hand, the probability of a service interruption on the Alaska gas project seems much higher than for the typical lower 48 pipeline. The Alaska gas project will be traversing a new environment for which there is little operating experience. Problems of frost heave, thaw settlement, weather induced maintenance and operating problems could mean a much greater incidence of service interruption. Also the Alaska gas project will be a single pipeline instead of the looped systems common in the lower 48. The probability of a single pipeline experiencing a major service interruption is higher than a looped system with its built-in redundancy and duplication of components.

In conclusion, the penalty for service interruption is much higher for lower 48 pipelines but the probability of service interruption is much higher for the Alaska gas project. On balance, it is difficult to decide which bears the greater financial risk due to service interruption.

Marketability Problems

A basic element of the financing plan for the Alaska gas project is the construction of a chain of contracts and other legal obligations that assures the flow of revenues from the ultimate consumer of natural gas, through the distribution companies and the interstate pipelines who are the shippers of the gas, and back to the project itself. However, there is a risk that events we can only barely imagine now might break that chain and cause a reduction in revenues to the project below that necessary to cover the full cost of service. In such an event, the equity investors would be the first to experience a reduction in return.

The most likely event that could cause a reduction in revenues is if it became difficult to market or sell the gas in the face of competition from other energy sources. Rolled-in pricing reduces this risk but does not eliminate it. Over the next 25 years, a sudden breakthrough in energy technology that reduced real energy prices is one example of an event that could endanger the marketability of the Alaska gas. This is a risk that is substantially greater for the Alaska gas project than for conventional lower 48 pipelines because of the higher transportation costs for Alaska gas.

Equity Capitalization

Though not strictly a risky event that could reduce or increase rates of return, the capital structure of the project plays an important role in determining the risk to equity investors. A small proportion of equity in the capital structure, i.e. a low equity ratio, means that any fluctuations in revenues due to any of the events described above would be multiplied into a large fluctuation in return to equity. Debt service and operating expenses must be paid before return to equity. Thus any fluctuations in revenue must be borne to the extent possible first by equity investors.

As an example, consider two capital structures for the Alaska gas project, a 0.25 equity ratio which is proposed by the sponsors and 0.45 which is the average for lower 48 pipelines. During the first years of operation, a five percent reduction in revenues would reduce return to equity by approximately 32 percent in the case of a 0.25 equity ratio but only 20 percent in the case of a 0.45 ratio. Thus the risk to equity investors for the Alaska gas project increases substantially due to the low equity ratio compared to the typical lower 48 pipeline.

A low equity ratio, however, substantially reduces costs to consumers. A 0.25 ratio and 13 percent return on equity would reduce the cost of service for the project by approximately 20 percent in the early years of operation compared to a 0.45 ratio and a 13 percent return. The Commission could grant a substantial increase in rate of return to compensate for the risks created by the low equity capitalization without increasing the total cost of service compared to more conventional capital structures and rates of return.

John B. Adger, Jr.
Alaskan Delegate
February 2, 1979

Corrected - February 5, 1979

Further Corrected - February 16, 1979

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